APS
Commitment. Innovation. Energy.

0000071483

RECEIVED
AZ CORP COMMISSION

JAN 9 11 46 AM '98

DOCUMENT CONTROL

P.O. Box 53999
Phoenix, AZ 85072-3999
http://www.apsc.com

January 9, 1998

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Arizona Corporation Commission
DOCKETED

JAN 09 1998

DOCKETED BY JH

Re: Docket No. U-0000-94-165

Dear Sir or Madam:

Pursuant to Arizona Corporation Commission's First Amended Procedural Order, dated December 11, 1997, it states, all "Affected Utilities" shall file direct testimony and associated exhibits on or before January 9, 1998.

Enclosed is direct testimony of Jack E. Davis, Executive Vice President, Arizona Public Service and William Hieronymus.

If you have any questions, please contact me at 250-2031.

Sincerely,

Barbara A. Klemstine

Barbara A. Klemstine
Manager
Regulatory Affairs

BAK/JKD/pb

Enclosure

For Parties of Record in Docket No. U-0000-94-165

COPIES of the foregoing were mailed and/or delivered on this 9th day of January, 1998 to the following:

Greg Patterson
RUCO
2828 N. Central Ave.
Suite 1200
Phoenix, Arizona 85004

Michael A. Curtis
MARTINEZ & CURTIS, P.C.
2712 N. Seventh Street
Phoenix, Arizona 85006

Walter W. Meek, President
ARIZONA UTILITY INVESTORS ASSOCIATION
2100 N. Central Avenue, Suite 210
Phoenix, Arizona 85004

Rick Gilliam
LAND & WATER FUND OF THE ROCKIES
2260 Baseline Road, Suite 200
Boulder, CO 80302

Charles R. Huggins
ARIZONA STATE AFL-CIO
110 N. Fifth Avenue
P.O. Box 13488
Phoenix, Arizona 85002

Norman J. Furuta
DEPARTMENT OF THE NAVY
900 Commodore Dr., Bldg. 107
P.O. Box 272 (Attn. Code 90C)
San Bruno, CA 94066-7020

Sam Defraw
(Attn. Code 16R)
Rate Intervention Division
NAVAL FACILITIES ENGINEERING COMMAND
200 Stovall St., Rm. 10512
Alexandria, Virginia 22332-2300

AJO IMPROVEMENT COMPANY
P.O. Drawer 9
Ajo, Arizona 84321

For Parties of Record in Docket No. U-0000-94-165

MOHAVE ELECTRIC COOPERATIVE, INC.
P.O. Box 1045
Bullhead City, Arizona 86430

MORENCI WATER & ELECTRIC COMPANY
P.O. Box 68
Morenci, Arizona 85540

Betty Pruitt
ARIZONA COMMUNITY ACTION ASSOCIATION
202 E. McDowell #255
Phoenix, Arizona 85004

Choi Lee
PHELPS DODGE CORPORATION
2600 N. Central Avenue
Phoenix, Arizona 85004-3014

Bradley Carroll
TUCSON ELECTRIC POWER COMPANY
P.O. Box 711
Tucson, Arizona 85702

Creden Huber
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE
P.O. Box 820
Willcox, Arizona 85644

Mick McElrath
CYPRUS CLIMAX METALS COMPANY
P.O. Box 22015
Tempe, Arizona 85285-2015

Dan Neidlinger
23020 North 17th Drive
Phoenix, Arizona 85015

Jessica Youle
SALT RIVER PROJECT
PAB 300
P.O. Box 52025
Phoenix, Arizona 85072-2025

Patricia Cooper
AEPCO
P.O. Box 670
Benson, Arizona 85602-0670

For Parties of Record in Docket No. U-0000-94-165

Clifford Cauthen
GRAHAM COUNTY ELECTRIC CO-OP
P.O. Drawer B
Pima, Arizona 85543

Marv Athey
TRICO ELECTRIC COOPERATIVE
P.O. Box 35740
Tucson, Arizona 85740

Wayne Retzlaff
NAVOPACHE ELECTRIC CO-OP, INC.
P.O. Box 308
Lakeside, Arizona 85929

Craig Marks
CITIZENS UTILITIES COMPANY
2901 N. Central Avenue, Suite 1660
Phoenix, Arizona 85012

Steve Kean
ENRON
P.O. Box 1188
Houston, Texas 77251-1188

Jack Shilling
DUNCAN VALLEY ELECTRIC COOPERATIVE
P.O. Box 440
Duncan, Arizona 85534

Ken Saline
K.R. SALINE & ASSOCIATES
P.O. Box 30279
Mesa, Arizona 85275

Phyllis Rowe
ARIZONA CONSUMERS COUNCIL
6841 North 15th Place
Phoenix, Arizona 85014

C. Webb Crockett
FENNEMORE CRAIG
Two North Central Avenue
Suite 2200
Phoenix, Arizona 85004-2390

For Parties of Record in Docket No. U-0000-94-165

DEPARTMENT OF THE NAVY
Sam DeFrawi
Navy Rate Intervention
901 "M" Street, S.E., Bldg. 212
Washington, DC 20374

Robert S. Lynch
340 E. Palm Lane, Suite 140
Phoenix, Arizona 85064-4528

Michael Block
GOLDWATER INSTITUTE
Bank One Center
201 N. Central, Concourse Level
Phoenix, Arizona 85004

John Branch
CITY OF MESA ELECTRIC UTILITY
P.O. Box 1466
Mesa, Arizona 85211-1466

Douglas C. Nelson, P.C.
7000 North 16th Street
Suite 120-307
Phoenix, Arizona 85020

Lawrence V. Robertson, Jr.
MUNGER CHADWICK, P.L.C.
333 North Wilmot, Suite 300
Tucson, Arizona 85711-2634

Tom Broderick
6900 E. Camelback Rd. #700
Scottsdale, Arizona 85251

Michael Grant
GALLAGHER & KENNEDY
2600 N. Central Avenue
Phoenix, Arizona 85004

Suzanne Dallimore
ATTORNEY GENERAL'S OFFICE
1275 W. Washington Street
Phoenix, Arizona 85007

For Parties of Record in Docket No. U-0000-94-165

Lex Smith
Michael Patten
BROWN & BAIN, P.C.
2901 N. Central Avenue
Phoenix, Arizona 85001-0400

Vinnie Hunt
TUCSON DEPARTMENT OF OPERATIONS
4004 South Park Avenue, Bldg. 2
Tucson, Arizona 85714

William Sullivan
MARTINEZ & CURTIS, P.C.
2716 North Seventh Street
Phoenix, Arizona 85006

Elizabeth S. Firkins
INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS L.U. #1116
750 South Tucson Boulevard
Tucson, Arizona 85716

Paul Bullis
Chief Counsel, Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Jerry Rudibaugh
Chief Hearing Officer
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Andrew W. Bettwy
Assistant General Counsel
SOUTHWEST GAS CORPORATION
5241 Spring Mountain Road
Las Vegas, Nevada 89102

Debra Jacobson Manager
State Regulatory Affairs
SOUTHWEST GAS CORPORATION
5241 Spring Mountain Road
Las Vegas, Nevada 89102

For Parties of Record in Docket No. U-0000-94-165

Roderick G. McDougall
CITY ATTORNEY
200 W. Washington St., Suite 1400
Phoenix, Arizona 85003-1611

William J. Murphy
200 W. Washington St., Suite1400
Phoenix, Arizona 85003-1611

Larry K. Udall
2712 N. Seventh Street
Phoenix, Arizona 85006-1090

Russell E. Jones
33 N. Stone Ave., Suite 2100
P.O. Box 2268
Tucson, Arizona 85702

Christopher Hitchcock
P.O. Box 87
Bisbee, Arizona 85603-0087

BARRY, HETZER, STICKLEY & SCHUTZMAN
Court Reporters
2627 N. Third Street, Suite 3
Phoenix, Arizona 85004-1103

Albert Sterman
ARIZONA CONSUMERS COUNCIL
2849 East 8th Street
Tucson, Arizona 85716

W:/winword/patb/servlist

BEFORE THE

ARIZONA CORPORATION COMMISSION

DOCKET NO. R-0000-94-165

TESTIMONY

OF

DR. WILLIAM H. HIERONYMUS

ON BEHALF OF

ARIZONA PUBLIC SERVICE COMPANY

January 9, 1998

TABLE OF CONTENTS

Testimony of W. H. Hieronymus

1. Introduction and Summary

Q. Please state your name, occupation and business address.

A. My name is William H. Hieronymus. I am a managing director of Putnam, Hayes & Bartlett, Inc., One Memorial Drive, Cambridge, Massachusetts 02142.

Q. Please briefly summarize your occupational experience and education.

A. I have nearly 25 years experience as a consultant specializing on the economic, business and policy issues affecting utilities, principally electric utilities. For the past 10 years, I have worked primarily on electric utility restructuring. This work began with the restructuring of the UK, New Zealand and continental European electricity sectors. For the past 5 years, it has focused on the US restructuring. I have worked on setting up the institutional structures to underpin competitive wholesale and retail markets, on utility mergers, and on asset valuation and stranded cost calculation. Much of this work has dealt with competition policy, particularly market power and its mitigation. It also has required extensive modeling and forecasting of competitive market prices.

In the 1980s, much of my work involved regulatory policy, including such topics as the nature of the regulatory compact, the consequences of the utility's obligation to serve and the appropriate definitions of "prudence" and "used and useful" as they related to that compact.

Turning specifically to stranded cost, which is the subject of this testimony, I have testified concerning the appropriateness of its recovery in Pennsylvania and on aspects of its quantification in Iowa and Pennsylvania.

I received a B.A. degree from the University of Iowa and Masters and Ph.D degrees in economics from the University of Michigan. My full resume is attached as APS Statement __ (WHH-1).

Q. Have you testified previously before the Arizona Corporation Commission?

A. Yes. I have done so on a number of occasions, most recently in Case No. ___, regarding appropriateness of Arizona Public Service's rate settlement.

Q. What is the purpose of this current testimony?

A. APS has asked me to respond on its behalf to several of the questions posed in the ACC's procedural order dated 1 December, 1997. This testimony constitutes at least a portion of its response to the issues identified in that order that are numbered 3, 6 and 9.

Q. Please summarize your conclusions.

A. Issue 3 is, what costs should be included in stranded costs and how should they be calculated? Regarding costs to be included, I conclude that the definition adopted by the ACC in Section R14-2-1601 is reasonably workable, at least as I interpret it, with the exception of ambiguity concerning the treatment of nuclear decommissioning and fuel disposal costs and the cut-off date for investments subject to stranded cost recovery. Regarding the method of calculation, I conclude that the lost revenues method is most appropriate.

Issue 6 is, who should pay for stranded costs? My conclusion is that stranded costs should be paid by all customers who would have paid the utility's generation cost of service under conventional regulation. This conclusion is consistent with the ACC's regulations, Section R14-2-1607(J) as I interpret that section. Concerning the allocation of stranded cost responsibility among customers, I conclude that the main principle should be the continuity of past ratemaking practices, resulting in minimal reallocation of costs.

Issue 9 is, what factors should be considered "mitigation"? My conclusion is that mitigation consists of those reasonable actions that a prudent and commercially oriented utility would take to minimize its costs of generation and/or maximize its net revenues for generation. It should not include cost shifting to investors or other parties, nor should it include compelling the generating activity to enter into non-traditional businesses or cross-subsidizing generation with revenues from other activities of the utility or its affiliates. Insofar as this is the ACC's intention in its definition of mitigation actions in Section 14-2-1607(A) of the ACC's regulations, that definition is incorrect.

2. Issue 3: What costs should be included as part of "stranded costs" and how should those costs be calculated?

Q. Please focus first on the first half of the question asked by Issue 3. What costs should be included as part of stranded costs?

A. The answer to this question is determined by the definition of stranded costs. Stranded costs are defined by the ACC as:

"..the verifiable net difference between:

a. The value of all the prudent jurisdictional assets and obligations necessary to furnish electricity (such as generating plants, purchased power contracts, fuel contracts, and regulatory assets), acquired or entered into prior to the adoption of this Article, under traditional regulation of Affected Utilities; and

b. The market value of those assets and obligations directly attributable to the introduction of competition under this Article.

An alternative, and I believe fully consistent definition is that stranded cost is the difference in value of the ongoing utility enterprise under the pre-existing fully regulated regime versus its value under the new competitive regime. This definition is "top down" in that it looks at the enterprise as a whole, whereas the ACC's definition is "bottom up" in that it is concerned with the value of specific assets and liabilities. However, if stranded cost is calculated properly, the two definitions are equivalent and will result in the same quantification of stranded costs. In this context, I note particularly that the value of the parts of the utility business unaffected by the change in regulation, such as distribution and transmission, will be essentially identical with and without the introduction of competition. For this reason, even a "top down" approach can, but does not need to, be restricted to the affected parts of the utility's former business.

The focus of both definitions on the difference in value between ongoing regulation versus competition is appropriate, since the primary intent of stranded cost recovery is to compensate utility investors for the loss (or gain) in value arising from a radical change in the "rules of the game".

Q. Can you explain why the top down and bottom up methods are equivalent?

A. Yes. Using the bottom up method, one compares the market value of each of the utility's assets and liabilities under the previous regulatory regime to their value under competition. As discussed later in my testimony, their value under competition is the cash flow or earnings (contribution to recovering fixed investment costs, hereafter called "contribution") they will yield to an owner, present valued at the owner's after tax discount rate. Their value under regulation is a similar stream of net present value of contribution, discounted at the utility's after tax regulated cost of capital. Necessarily, the contribution earned by the enterprise is equal to sum of the contributions earned by each of its assets under both market and regulated conditions. Hence, the top down and bottom up methods are equivalent. I have a mild preference for the top down method, partly because of computational ease and partly because it assures that nothing is left out in calculating net stranded costs.

Q. What are the main classes of stranded cost identified in the ACC's regulations?

A. The definition quoted above allows stranded cost recovery in respect of all assets and obligations. It specifically (but, presumably without prejudice to other sources of stranded cost) enumerates four types:

- Stranded generating plant,
- Stranded power contracts,
- Stranded fuels contracts, and
- Stranded regulatory assets and liabilities.

This focus generally is appropriate since it is the commodity cost of bulk power (the generation rather than the wires components) that is being shifted from a regulated cost basis to a market basis. Hence, it is power costs, whether the power is produced from owned generation or under the terms of purchase contracts, that is a main source of stranded cost. If market prices are expected to be below the generation part of cost of service rates, then generation is worth less in the new regime than it would have been worth under continuation of the previous regulatory regime.

The reasons for including regulatory assets and obligations as stranded costs are different than those that apply to stranded generating costs and contracts. Regulatory assets are "promises to pay" in the future for costs that were incurred in the past. An example in APS's case is the Palo Verde deferrals, reductions in the regulated cost of power produced several years ago that are being amortized in the future. Another example is accelerated tax depreciation that was used to reduce past regulated cost but lead to higher future tax liabilities. There may be other obligations relating to past utility activities that are not shown as regulatory assets on the utility's books. Since these assets and obligations produce no revenues outside of regulation, their competitive value is zero, and what is stranded is the full value of them under regulation.

Q. Are you aware of provisions for recovering APS's regulatory assets and liabilities that already are in place?

A. Yes. My understanding is that the ACC has approved amortization of APS's regulatory assets and liabilities over an 8 year period. Therefore, these costs are not stranded and need not be considered further.

Q. Does APS have any stranded power purchase costs?

A. My understanding is that APS's sole long term power purchase contract is its Territorial and Contingent contract with Salt River Project. There may be stranded costs associated with this contract.

Q. Does APS have any stranded fuels contracts?

A. APS has several coal contracts, at least one of which is above market in price. However, if stranded generating costs are calculated properly, the effect of above-market fuels contracts will already have been factored into the stranded cost calculation for generation, since the contribution to fixed costs and profit made by a coal plant that has above market fuel cost will be reduced by the amount of the above market cost of fuel.

Q. Are there other categories of stranded costs, beyond the four that the ACC regulations enumerate, that Arizona utilities may face?

A. Yes. Stranded costs other than the four identified categories may exist depending on the nature of the change in regulation. The ACC regulations appear to provide for deregulation of metering and meter reading services and of billing and collection services. If metering and billing are opened up to competition there may be stranded costs associated with the undepreciated value of meters and information technology systems or with the severance of associated staff.

Another area of potentially important stranded cost is overheads, or administrative and general (A&G) expense. It generally is assumed that, at a minimum, transmission and distribution will remain rate-regulated activities. A&G that is allocated to those activities will be recoverable through rates, as at present. However, A&G that will be allocated to non-rate regulated activities, principally generation, and therefore not recovered in cost-based rates, is potentially strandable. One way in which this can be taken into account is to include associated A&G in computing the value of generation assets. That is, in computing the value of generating assets for stranded cost purposes, generation costs should include not only plant-level costs but also allocable A&G.

Another category of stranded costs arises from the financial restructuring that can accompany stranded cost recovery. The shrinkage of the utilities balance sheet that accompanies the early depreciation and amortization of its assets requires a parallel shrinkage of the liability and net worth side of its balance sheet. This may require the repurchase of its securities. Early repurchase generally will mean that penalty provisions for repurchasing debt and preferred are triggered. There also are costs associated with repurchasing equity. Generally, these financial-related costs are a relatively small part of stranded cost. However, in jurisdictions where utilities are required to sell significant assets as a part of restructuring, these costs can be significant.

Q. The ACC's definition of stranded cost appears to limit assets and liabilities eligible for stranded cost recovery to those that were "acquired or entered into prior to the adoption of this Article". Do you agree with this restriction?

A. I agree with the ACC's intent, which I take to be putting utilities on notice. However, it simply is not appropriate to ignore all investments and obligations subsequent to December 31, 1996.

One example is metering investments made in 1997 (and that will have to be made in 1998 and beyond). Despite the fact that the ACC's regulations state that these will not be regulated monopoly activities, APS continues to have an obligation to hook up and meter all of its customers.

A second example is future capital investments in generating stations. Even if such investments are not themselves properly eligible for inclusion in stranded cost, they still must be taken into account in determining stranded cost. A simple example is, suppose that environmental regulations require putting a new type of control on emissions at APS's coal stations. If this is not done, the stations are valueless. Computing the contribution earned by those stations under competition must take into account the cost of the controls. Alternatively, such retrofits can be thought of as necessary mitigation, required to raise the value of the stations from zero to a significant positive value. While this example is hypothetical, there are other capital investments that are required if APS's generation is to operate and earn the contributions that are offset against the regulatory value of its assets in determining stranded costs. The cost of such investments must be taken into account.

Q. Turning to the question of stranded cost measurement generically, what methodologies have been proposed for calculating stranded costs?

A. Because recovery of APS's regulatory assets already has been provided for, I will answer this question only for generating assets. The calculation of stranded costs, if any, for its purchase contract will be similar.

There are several competing methods for calculating stranded generating costs. These are:

- The revenues lost method. This method begins by calculating "stranded" or lost revenues. Lost revenues are the difference between those that the utility would have received under continued regulation versus those that it will receive under competition. Under circumstances when costs also vary between the two regimes (e.g. sales may be greater under competition, resulting in higher fuels costs), lost revenues are usually computed as the reduction in the after tax contribution to investors (i.e., the return "on and of" investments). This is revenues less variable costs and other "going forward" costs of operation such as fixed O&M, capital additions and so forth. For the reasons discussed above, costs deducted from revenues include allocated A&G expense.

Lost revenues can be calculated on either a book basis or a cash flow basis. The difference between the two methods is a timing difference that, on a discounted basis over the life of the asset, is immaterial.

The lost revenues method, as generally employed, requires a year-by-year calculation of lost revenues or contribution. Stranded cost is simply the net present value of the stream of stranded costs over the period for which the calculation is being performed.

- The book-versus-market contribution method. This method is very similar to the lost revenues approach. As with the lost revenues method, the concept behind it is that the market value of a generating facility is the present value of its future earnings in a competitive environment. Stranded cost is the difference between this market value and book value.

Market value is calculated as the net present value of earnings (or cash flows) which, in turn, are the annual revenues at market prices less the costs of producing the power that earns the revenues. As in the lost revenues approach, the relevant costs include fuel, O&M, future capital additions and decommissioning expense, allocable A&G and, if earnings rather than cash flows are used, depreciation.

Because the present value of regulated revenues, calculated on an after tax basis and discounted at the utility's after tax cost of capital, are equal to the book value of the asset for which the calculation is made, their book value is equal to the present value of contributions used in the lost revenues method. Hence, this approach should lead to a calculation of stranded cost that is identical to the lost revenues approach if the calculation is performed over the entire remaining life of the asset. It cannot readily be used if stranded costs are calculated over a shorter period.

- Estimated "willing buyer-willing seller" sales value. To the extent that the ACC relies on evidence of prices received for the sale of generation stations sold by other utilities and non-utility generators, valuation will be performed on much the same basis as is used in appraising real estate.
- Outright sale. A way of establishing the market value of an asset is to sell it. Market value is the price that the asset sold for. The difference between market price and book value is stranded cost.
- Partial sale. At least one regulatory jurisdiction has required that a utility sell a part of its generation. If this is sold on a "slice" basis -- e.g. 10 percent of each facility -- the sales price can be used to establish the value of the remainder.

Q. Are any of these methods always preferable?

A. No. The problem with the first two methods is that forecasts of future costs and revenues are uncertain. The further out in time that one seeks to forecast, the more uncertain they become. Hence, there is a risk that stranded costs will be substantially mis-estimated.

This risk of mis-estimation is one reason why some regulatory commissions and utilities favor truing up stranded cost estimates during the transition period.

The willing buyer-willing seller suffers from the sparcity of comparable transactions and the difficulty of "adjusting" for non-comparable conditions. APS's generation is primarily coal and nuclear. The only coal plants that have been sold are in New England and the midwest, where market conditions are quite different from Arizona. No nuclear plants have been sold, at least none at positive prices. APS's gas plants have better comparables from the recent California sales. However, the value of individual stations in California is not transparent, since they were sold in bundles. Several of the California units are under must run contracts and their sale prices are not representative of competitive values. There also are structural and price differences between the California and Arizona markets as well as unit-specific differences that would have to be taken into account, such as age and condition, environmental liabilities and alternative use value for the plant sites.

Outright sale makes the current market value of sold generation assets unambiguous. Sale of at least a portion of generating assets also may be necessary under circumstances where the existing pattern of ownership is inconsistent with competition. However, it also has a number of disadvantages. First, it does not avoid the need to forecast uncertain market prices, cost and unit performance. It merely shifts that burden from the regulator to the buyers. Indeed, my company has assisted a number of potential buyers of generating stations in determining what to bid. In all cases, determining market value has centered on estimating future costs and revenues under competition, the same uncertain activity that underlies the first two methods of stranded cost quantification.

Consequently, the risk that the cost of stranded cost recovery will be too high from the standpoint of ratepayers is not eliminated or materially diminished. Further, outright sale eliminates the ACC's ability to use a future "true-up" to correct initial mis-perceptions of costs and prices.

Second, a substantial sale of assets disturbs the ability of the incumbent utility to meet residuary load obligations. The initial evidence from California appears to be that only very small numbers of customers have elected to switch to other suppliers when given the opportunity to do so. Presumably, the incumbent Arizona utilities will have an obligation to supply customers who elect not to switch. While this could be accommodated by a power contract between the utility and the purchaser of the assets, the terms of such contracts then become an important determinant of asset value, undercutting the validity of outright sale as a means of measuring asset value.

Third, asset sale has substantial transaction costs, including taxes on the gain over the tax basis of the assets, refinancing (both the "shrink" the company and to cure bondable property and other indenture defaults) and the cost of the sale itself.

Fourth, sale may not be feasible. First, while I am not opining on the facts of the specific case in Arizona, it often has been held that the regulatory commission lacks the authority to order divestiture of assets. Second, in the case of APS, it is likely that most of its stranded generating costs are associated with the Palo Verde nuclear plant. Despite several efforts, there have been no cases of a successful sale of a nuclear station, or even a share of a nuclear station, for many years. Such failures include quite recent attempts.

The last option, partial sale, shares the defects and advantages of outright sale but to a lesser degree. The only additional point to be made uniquely about a partial sale is that it has unknown, but potentially significant, defects as a means of calculating the value of the remainder of the facilities. First, it may yield too high of a value. The sale is made to the buyer willing to pay the most. Since the market price of any asset or product generally is lower, the more of it is available, the price of the first "slice" should overstate the value of the remainder. Conversely, it generally is believed that there is a "control premium": a buyer that believes that it could make an asset more valuable if it controlled it will pay less for a slice of assets that will still be controlled and operated by the incumbent utility.

Q. Given that each method has advantages and disadvantages, which method do you recommend that the ACC adopt?

A. I recommend the lost revenues or book-versus-market methods, which I have indicated are essentially equivalent. This is the same approach as was adopted by the FERC in Order No. 888 after receiving wide-ranging comments from proponents of each of the approaches that I have discussed.[1] It is also the approach used in the Pennsylvania stranded cost proceedings, which are the farthest advanced of any state proceedings on stranded cost quantification. It was used in California,, albeit in rudimentary form, in estimating stranded costs for securitization purposes.

I recommend the lost revenues method with full knowledge of the difficulty of estimating value. However, the uncertainty of future value can be reduced sharply if the ACC elects

---

[1] The FERC method, which it calls the "revenues lost" method, differs in some respects from the forecast-based methods that are more conventional. Lost revenues are the average paid by the departing wholesale customer in the previous three years. These are offset by market revenues that are either the customer's acquisition cost of replacement power or the utility's estimate of the market value it will receive for the power released by loss of the wholesale customer. The customer also has the alternative of taking the power and brokering (reselling) it if it believes it can get a higher value from it than the utility's estimate. Using historic prices paid by customers likely would overstate stranded costs for APS's retail customers due to rate decreases. The brokering option probably is not feasible for retail access customers.

some form of true-up, as its regulations at R14-2-1607(L) permit. Further, the uncertainty about future value, which increases over time the more distant is the period for which market prices are being calculated, is sharply reduced by discounting. Assuming that the period of stranded cost recovery in Arizona is in the 4 to 10 year range adopted by other regulatory commissions, most of the value uncertainty is contained within this transition period. Further, if the stranded cost calculation period is limited to the transition period, as I understand to be APS's proposal for its stranded cost recovery, then post-transition stranded costs are zero by definition.

Q. Does the lost revenues method net off "stranded benefits" from the calculation of stranded costs?

A. Yes. Stranded benefits are negative stranded costs. They arise because some utility assets are worth more under competition than they are allowed to earn under regulation. Under "top down" methods of determining stranded costs, these benefits are automatically used to reduce the calculated net amount of stranded costs. Under bottom-up methods, the negative stranded cost amount would be calculated on an asset-specific basis, then deducted from the aggregate amount.

Q. Are there any strandable costs that should be recovered independently from any stranded cost recovery mechanism?

A. Yes. The main candidate is nuclear decommissioning costs and the related fuel disposal costs incurred prior to the end of transition. Decommissioning costs clearly relate to the past operations of nuclear plants. Once a nuclear plant is thoroughly irradiated, the scope of decommissioning requirements is set. Indeed, further operation, by deferring the need to decommission, actually reduces the present value of decommissioning cost. Hence, the full amount of decommissioning cost, which clearly is "stranded", is appropriately recovered as part of any transition mechanism. However, decommissioning will not take place until the distant future and costs are highly uncertain. For that reason, decommissioning costs should continue to be recovered through some form of non-market rate component over the remaining life of Palo Verde. Special treatment of fuel disposal costs also is warranted by the considerable uncertainty concerning whether the federal government will honor its commitment to dispose of spent fuel in return for the payments that nuclear station owners have made. Since the regulated cost of nuclear output recovered in the past has assumed that this commitment will be honored, any additional costs related to that output that are incurred in the future are stranded costs not reflected on the current balance sheet.

3. Issue 6: How and who should pay for "stranded costs" and who, if anyone, should be excluded from paying for stranded costs?

Q. Who should be required to pay stranded cost charges?

A. Stranded cost charges should be paid by all customers who would have paid APS's regulated generating costs under the current set of rules. Effectively, this means that they should be paid by all customers physically located in APS's service area, taking service over APS's wires. It does not include customers who leave the system or the territory.

This is consistent with the decision reached by FERC in Order 888, which exempts only customers that wholly leave the utility's system, including disconnecting from transmission.

Q. Does this recommendation mean that customers who do not leave the utility's regulated bundled service will also have to pay stranded cost charges?

A. Implicitly or explicitly, stranded cost charges should be paid by both customers that leave regulated retail service and those that do not. If non-leavers continue to pay cost of service-based rates for power, then, by definition, there will be no stranded costs for such customers during the period during which they remain bundled service customers. Stating the same point differently, stranded cost recovery will be automatic from such customers.

Notwithstanding this fact, several regulatory authorities have chosen explicitly to assess stranded cost charges for non-leaving customers. Such assessment is useful, even necessary, under either of two circumstances and is not necessary when they do not apply. First, if the year-to-year time profile of stranded cost recovery during the transition period is different from the profile of cost-based recovery in the bundled rates, equity would require customizing stranded cost recovery for customers who left bundled service at some future point during transition. A separate and explicit charge for stranded cost for non-leaving customers that is identical to that paid by leavers eliminates the need for this complex customization. A second and related reason is that many regulatory commissions have accelerated recovery of post-transition stranded costs into the transition period. Equity requires that non-leavers pay their fair share of these post-transition charges; otherwise they could evade them by delaying leaving until after transition. For example, if APS's proposal is rejected or modified in a manner that brings post-transition stranded costs into the recovery, then an explicit recognition of such stranded cost will be required for non-leaving customers.

Of course, if stranded costs are collected from non-leavers, it is necessary to reduce the remaining elements of bundled service rates to avoid double counting.

Q. How should stranded cost charges be assessed to individual customers?

A. At the customer level, stranded costs are the difference between what they would have paid under unchanged regulation versus what they would pay if they bought retail service from non-APS sources based on market costs for bulk power.[2] At least approximately, the customer's allocation of stranded cost charges should reflect this difference.

This means that stranded cost billing elements should reflect the way in which the generation portion of rates is determined today. Since, ultimately, the capacity and energy-related costs of generation are converted into kW and kWh charges (with the latter time-differentiated for some classes of customers), the non-disturbance of rates means that these same billing elements should be used for cost recovery.

Non-disturbance also means that contract rates should not be impacted by stranded cost recovery for the remaining period of the contracts.

While non-disturbance of rates should be the main guiding principle for developing stranded cost charges, the ACC may wish to determine the extent to which the movement to competition will change relative rate levels and use the allocation of stranded cost recovery responsibility to somewhat smooth the transition. Otherwise, at the end of the transition period, customers will see a large sudden movement in rates, upward in some cases. To give a concrete example, in the UK the movement of generation to a market

---

[2] This is similar to FERC's concept of "direct assignment" used to calculate the stranded cost responsibility of departing customers.

basis caused rates for some types of customers to go up by as much as 20 percent and rates for others to decline by similar amounts. Note that the potential problem is not limited to past cross-subsidy among customer classes or customers within a class. Competition can change the cost of serving different types of customers in a way that means that formerly equitable rate structures will now include cross-subsidies.

4. Issue 9: What factors should be considered for "mitigation" of stranded costs?

Q. What mitigation ought be taken into account in calculating stranded costs?

A. Fundamentally, stranded cost calculation should be premised on the expectation that over the transition period the utility's generation will come to be run as efficiently and effectively as can be expected of competitive producers. In some cases, this may mean cost reductions or performance improvements. If a generation unit cannot cover its avoidable cost, the utility can be expected to close it. Utilities also can be held accountable for selling output at market prices.

Beyond simply operating at high levels of competence, it is unclear what is meant by "mitigation". Mitigation means "to make less severe, to moderate". Hence, mitigation actions are those that reduce stranded cost. A commonly intended meaning of the term is that where utilities have bad contracts that can be cost effectively renegotiated, that those renegotiations should take place. This genuinely is mitigation. Conversely, a redistribution of an undiminished stranded cost by, for example, requiring that shareholders bear some portion of it is not mitigation.

In Order No. 888, FERC concluded that mitigation was automatic under its version of the lost revenues method of stranded cost calculation on the grounds that the utility would have an obligation and incentives to market the capacity and energy that is released by the loss of the customer at market rates:

> "Contrary to the objections of some commentaries that the revenues lost approach creates no incentive to mitigate stranded costs, the formula automatically encompasses mitigation by reducing the departing generation customer's stranded cost obligation by the competitive market value of the released capacity and associated energy." (slip Opinion at p. 599).

FERC then went on to explicitly decline to "impose a separate mitigation obligation on the utility above that which is already subsumed in the revenues lost approach." It did, however, note that, "In addition, a utility will continue to be subject to an ongoing prudence obligation to sell excess capacity off-system and/or to dispose of uneconomic assets." FERC's reference to an ongoing, or continuing "prudence" obligation fairly raises the question of whether the calculation of stranded cost does, or should, create any obligation to "mitigate" that the utility did not have already. Utilities have long had the obligation to take those actions available to a prudent management to minimize their cost of service. The events of stranded cost calculation and/or of making power markets competitive, does not give utilities any material new means of "mitigating", or reducing costs that they did not have previously. Hence, "mitigation" does not impose any new or higher requirement than has existed in the past. All that is new is the requirement to effectively market the energy and capacity that was previously dedicated to native load customers.

Q. Do the ACC's regulations reflect a definition of mitigation that is consistent with your or FERC's definition?

A. They do not appear to, though it is not clear whether this is merely a semantic difference. For example, R14-2-1607(B) states: "The Commission shall allow recovery of <u>unmitigated</u>

Stranded Cost by Affected Utilities", and R-14-2-1607(G) states, in relevant part, that: "The Affected Utilities shall file estimates of unmitigated Stranded Cost" (emphasis added). Since mitigation includes, and indeed consists primarily of, selling the freed-up energy and capacity at market prices, an "unmitigated" estimate of stranded cost would be the gross cost of serving departing customers. The definition of unmitigated stranded cost implicit in these subsections is not consistent with the ACC's own definition of stranded cost, cited above, which defines them as the net difference between asset values under regulation versus competition.

Another potential difference is found in R14-2-1607(A) which is the sub-section of the regulations that comes closest to defining mitigation. This section reads:

> "The Affected Utilities shall take every feasible, cost-effective measure to mitigate or offset Stranded Cost by means such as expanding wholesale or retail markets, or offering a wider scope of services for profit, among others."

I agree that mitigation should include maximizing the value of released capacity by expanding sales where it is possible and cost-effective to do so. However, it is less clear what the ACC means by "offering a wider scope of services for profit." There are no "services" available from regulatory assets and obligations and no non-power services of any consequence available from generation. Thus, the subsection raises a concern in my mind that the ACC intends that Affected Utilities engage in unregulated, non-utility businesses and that the profits from those businesses be used to offset stranded cost. Confiscating profits from unregulated businesses to cover stranded costs, even if lawful, is not "mitigation" and is simply a ruse to avoid the payment of stranded costs. The ACC should clarify that it is not its intent to confiscate the profits of unregulated affiliates of

Affected Utilities as an offset to stranded costs. It also should make it clear that "mitigation" does not require that Affected Utilities enter into non-utility businesses for any reason. Such a requirement would carry with it a ratepayer responsibility to cover any losses of such businesses. Forcing the state's utilities into non-utility businesses is not merely bad public policy but also is quite likely to be a bad business decision, at least based on the lessons learned from the experience of utilities generally, and southwestern utilities in particular, in profitably operating non-utility businesses.

Q. Does this complete your testimony?

A. Yes.

WILLIAM H. HIERONYMUS **Managing Director**

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators and policy makers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy and regulatory issues. He has spent the last several years working on restructuring and privatization of utility systems internationally and on changing regulatory systems and management strategies in mature electricity systems. In his twenty-plus years of consulting to this sector he also has performed a number of more specific functional tasks including the selection of investments, determining procedures for contracting with independent power producers, assistance in contract negotiation, tariff formation, demand forecasting and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of utility clients before regulatory bodies, federal courts and legislative bodies in the United States and United Kingdom. Since joining Putnam, Hayes & Bartlett, Inc. (PHB) he has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Assignments

- Dr. Hieronymus served as an advisor to a western electric utility on restructuring and related regulatory issues and has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. As a part of this general assignment he helped develop, and testified respecting, a settlement with the state regulatory commission staff that provides, among other things, for accelerated recovery of strandable assets. He also prepared numerous briefings for the senior management group on various topics related to restructuring.

- For several utilities seeking merger approval he has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The analyses he has sponsored cover the destination market-oriented traditional FERC tests, Justice Department-oriented market structure tests similar to the Order 592 required analyses, behavioral tests of the ability to raise prices and examination of vertical market power arising from ownership of transmission and generation and from ownership of distribution facilities in the context of retail access. The mergers on which he has testified include both electricity mergers and combination mergers involving electricity and gas companies.

- For utilities and power pools preparing structural reforms, he has assisted in examining various facets of proposed reforms. This analysis has included both features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For the New England Power Pool he examined the issue of market power in connection with its movement to market-based pricing for energy, capacity and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC.

- As part of a large PHB team he assisted a midwest utility in developing an innovative proposal for electricity industry restructuring. This work formed the basis for that utility's proposals in its state's restructuring proceeding.

- Dr. Hieronymus has contributed substantially to PHB's activities in the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation.

- He has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of the utilities' assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which the utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs and assisted companies in internal stranded cost and asset valuation studies.

- He has contributed to the development of benchmarking analyses for U.S. utilities. These have been used in work with PHB's clients to develop regulatory proposals, set cost reduction targets, restructure internal operations and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package that PHB has tailored to region-specific applications. He and other PHB personnel have provided numerous multi-day training sessions using the package to help our utility clients in educating management personnel in the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- Dr. Hieronymus has made numerous presentations to U.S. utility managements on the U.K. electricity system and has arranged meetings with senior executives and regulators in the U.K. for the senior managements of U.S. utilities.

- For a task force of utilities, regulators, legislators and other interested parties created by the Governor's office of a northeastern state he prepared background and briefing papers as part of a PHB assignment to assist in developing a consensus proposal for electricity industry restructuring.

- For an East Coast electricity holding company, he prepared and testified to an analysis of the logic and implementation issues concerning utility-sponsored conservation and demand management programs.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico and before the Federal Energy Regulatory Commission in plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant cost for tariff setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that are currently under construction. His testimony has covered the likely cost of plant completion, forecasts of operating performance and extensive analyses of ratepayer and shareholder impacts of completion, deferral and cancellation.

- For utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning continuing the construction projects. Areas of inquiry included plant cost, financial feasibility, power marketing opportunities, the impact of potential regulatory treatments of plant cost on shareholders and customers and evaluation of offers to purchase partially completed facilities.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major midwestern utility, he headed a team that assisted senior management in devising its strategic plans including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition and diversification opportunities.

- On behalf of two West Coast utilities, he testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, Dr. Hieronymus participated in a major 18-month effort to provide it with an integrated planning and rate case management system. His specific responsibilities included assisting the client in design and integration of electric and gas energy demand forecasts, peak load and load shape forecasts and forecasts of the impacts of conservation and load management programs.

- For two midwestern utilities, he prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee..

- For a major combination electric and gas utility, he directed the adaptation of a PHB-developed financial simulation model for use in resource planning and evaluation of conservation programs.

U.K. Assignments

- Following promulgation of the White Paper setting out the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional electricity councils focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, he assisted several of the U.K. individual electricity companies in understanding the evolving system, in development of use of system tariffs, and in developing strategic plans and management and technical capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for an 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- He also has consulted on the separate reorganization and privatization of the Scottish electricity sector. PHB's role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation and company strategy.

- He has assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment have been policy issues such as incentives for economic purchasing of power, the scope of the price control, and the use of comparisons among companies as a basis for price regulation. His model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted this same utility in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus has assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that *inter alia* requires retail access and competitive markets for generation. The assignment includes advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development he performed analyses of least cost power options, evaluation of the return on a major plant investment that the Bank was considering and forecasts of electricity prices in support of assessment of a major investment in an electricity intensive industrial plant.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, he developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command and control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which is to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization will be based on regional electricity companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, he continued to advise the Russian energy and power ministry and government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company he analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electric generating and electricity distribution industries in New Zealand, he undertook an analysis of industry structure and regulatory alternatives for achieving economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.
- For EPRI, he directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.
- For the EPRI-NARUC Rate Design Study, Dr. Hieronymus developed a methodology for designing optimum cost-tracking block rate structures.
- On behalf of a group of cogenerators, he filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.
- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines on fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guideline on cost-of-service standards.
- For private utility clients, he assisted in the preparation of comments on draft Federal Energy Regulatory Commission (FERC) regulations and in preparing their compliance plans for PURPA Section I33.
- For the EEI Utility Regulatory Analysis Program, he co-authored an analysis of the DOE position on the purposes of the Public Utilities Regulatory Policies Act of 1978. The report focused on the relationship between those purposes and cost-of-service and ratemaking positions under consideration in the generic hearings required by PURPA.
- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.
- For the DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.
- For the commissioners of a public utility commission, he assisted in preparation of briefing papers, lines of questioning and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force and formed an important basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, he developed a load forecasting model designed to interface with the utility's revenue forecasting system- planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.
- For the DOE, he directed the development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and constructed a forecasting model for their interim use.
- For several state regulatory commissions, Dr. Hieronymus has consulted in the development of service area level forecasting models of electric utility companies.
- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.
- For a midwestern electric utility, he has provided consulting assistance in improving its load forecast and has testified in defense of the revised forecasting models.
- For an East Coast gas utility, he testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These include both Sherman Act Section One and Two cases, contract negotiations, generic rate hearings, ITC hearings and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor he has testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, he is assisting clients in responding to the Antitrust Division of the U.S. Department of Justice's Hart-Scott-Rodino requests.

- For a private client, he headed a project that examined the feasibility and value of a major synthetic natural gas project. The study analyzed both the future supply costs of alternative natural gas sources and the effects of potential changes in FPC rate regulations on project viability. The analysis was used in preparing contract negotiation strategies.

- For a industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, he developed an estimate of the potential market for the system by geographic area.

- For the U.S. Environmental Protection Agency (EPA), Dr. Hieronymus was the principal investigator in a series of studies for forecasting future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has addressed a number of conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervenor strategies in utility regulatory proceedings, utility deregulation and utility-related opportunities for investment bankers.

Before joining PHB, Dr. Hieronymus was program manager for Energy Market Analysis at Charles River Associates. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving in the U.S. Army. He is a present or past member of the American Economics Association and the International Association of Energy Economists, and a past member of the Task Force on Coal Supply of the New England Energy Policy Commission. He is the author of a number of reports in the field of energy economics and has been an invited speaker at numerous conferences.

Dr. Hieronymus received a B.A. from the University of Iowa and M.A. and Ph.D. degrees in economics from the University of Michigan.

BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF JACK E. DAVIS

On Behalf of

Arizona Public Service Company

Docket No. U-0000-94-165

January 9, 1998

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

JACK E. DAVIS

(Docket No. U-0000-94-165)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jack E. Davis, and my business address is 400 North Fifth Street, Phoenix, Arizona 85004

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Executive Vice President of Commercial Operations for Arizona Public Service Company ("APS" or "Company"). My educational and professional qualifications and experience are set forth in Schedule JED-1, which is attached to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will address certain of the issues set forth in the Commission's Procedural Orders of December 1 and December 12, 1997. These include what I consider policy issues and what might be viewed as unique APS approaches to the stranded cost problem. Later in my testimony, I identify specific changes to the Commission's electric competition rules ("the Rules") that are consistent with my testimony and that of Dr. William H. Hieronymous, a nationally recognized expert in the area of electric industry restructuring and stranded costs.

II. SUMMARY

Q. WOULD YOU SUMMARIZE THE COMPANY'S RESPONSE TO EACH OF THE ISSUES IDENTIFIED IN THE DECEMBER PROCEDURAL ORDERS?

A. Yes. Set forth below are the issues listed in the December Procedural Orders along with a summary of the APS response as set forth in my testimony and that of Dr. Hieronymous:

Issue No. 1 - Should the Electric Competition Rules ("Rules") be modified regarding stranded costs, if so how?

Response - Yes. The definition of stranded costs should be clarified relative to nuclear fuel disposal costs, the scope of required mitigation, the inclusion of post-1996 costs, and the permissible classes of customers and services through which stranded cost recovery can be effectuated. Attached is a mark up of the Rules that will reflect these changes.

Issue No. 2 - When should "Affected Utilities" be required to make a "stranded cost" filing pursuant to A.A.C. R14-2-1607?

Response -Under the Company's proposal, no single stranded cost filing is required. It would, however, propose to submit its calculation of 1999 stranded costs no later than thirty (30) days after receiving a final order in this proceeding.

Issue No. 3 - What costs should be included as part of "stranded costs" and how should those costs be calculated?

Response -The definition of stranded costs set forth in the Rules is generally adequate. However, the treatment of nuclear fuel disposal and post-1996 costs needs clarification as noted above. Moreover, regulatory assets, although a component of stranded costs under the Rules, are treated separately pursuant to the Commission's direction in Decision No.

59601 and are not therefore included in the Company's calculation of stranded costs. Stranded power supply costs should be calculated using the Company's variant of the "lost revenues" method.

<u>Issue No. 4</u> - Should there be a limitation on the time frame over which "stranded costs" are calculated?

<u>Response</u> -Most definitely. APS believes they should be calculated only during the period of market imbalance which it has forecasted will end by the end of 2006.

<u>Issue No. 5</u> - Should there be a limitation on the recovery time frame for "stranded costs?"

<u>Response</u> -In general, the recovery period should be as short as possible, and in APS' proposal would be the same time frame over which the costs are calculated.

<u>Issue No. 6</u> - How and who should pay for "stranded costs" and who, if anyone, should be excluded from paying for stranded costs?

<u>Response</u> -All APS customers (including partial requirements or back up customers) should pay a fair share of stranded costs. Only those who physically relocate from its service area or who completely disconnect themselves from the APS system should, as a practical matter, be exempted.

<u>Issue No. 7</u> - Should there be a true-up mechanism and, if so how would it operate?

<u>Response</u> -As a general proposition, true-up mechanisms should be kept to a minimum. Under the APS proposal, only the first year's (1999) estimates of market price would necessitate any true-up.

Issue No. 8 - Should there be price caps or a rate freeze imposed as part of the development of a stranded cost recovery program and if so, how should it be calculated?

Response -APS makes no such proposal at this time.

Issue No. 9 - What factors should be considered for "mitigation" of stranded costs?

Response -The proper scope of mitigation is limited to cost reductions and generation revenue enhancements reasonably achievable during the same period of time allowed for stranded cost recovery. Moreover, the Commission must recognize past efforts by APS to reduce costs and prices as a result of the 1991, 1994 and 1996 rate agreements.

Issue No.10- What are the FASB No. 71 implications resulting from the Company's recommended calculation and recovery of stranded cost recovery?

Response-None are immediately evident under the Company's proposal because APS has developed an approach to stranded cost recovery that essentially eliminates the many complex issues that could otherwise arise under other approaches.

Issue No. 11-[What are the] assumptions made including any determination of market price?

Response-The Company's proposed method does not require assumptions about market price or generation costs because it would use actual data.

Q. HAVE YOU PRIORITIZED THE ISSUES ADDRESSED IN YOUR TESTIMONY AS REQUESTED BY THE DECEMBER PROCEDURAL ORDERS?

A. Yes, at least as much as is possible. My summary below lists the issues in order of importance to the Company. To the extent the subsequent text of my testimony departs from that order of importance, such departure is solely for the sake of continuity and to reflect a logical grouping of related (but not necessarily equally important) issues.

Q. WOULD YOU SUMMARIZE YOUR CONCLUSIONS ON STRANDED COSTS?

A. Yes. Stranded cost is not a single issue, but a complex and interrelated set of issues that must be resolved by the Commission prior to the initiation of retail competition in 1999. This will require evidentiary hearings subsequent to those presently scheduled but need not involve a full-blown general rate case unless the "Affected Utility" is simultaneously seeking to increase its current rates and charges. Second, both the measurement and recovery of stranded generation costs should be limited to a specified transition period ("Transition Period"), with rates for competitive generation being fully deregulated thereafter. The "lost revenues" method is the appropriate means of determining APS stranded generation costs during this Transition Period. Third, the Commission must properly limit the concept of stranded cost mitigation to reasonable cost reduction and generation revenue enhancement efforts. Fourth, the recovery of "regulatory assets" is not, at least for APS, a stranded cost issue for the simple reason that recovery of such assets has already been ordered by the Commission in Decision No. 59601. Fifth, stranded cost recovery should reflect traditional cost allocation and rate design considerations.

Q. PLEASE SUMMARIZE YOUR PROPOSALS TO AMEND THE COMMISSION'S CURRENT RULE ON STRANDED COSTS?

A. The current mitigation provisions of the Rule are unreasonable and counterproductive and should be amended. Second, the definitions of both "stranded costs" and "system benefits" should be clarified to recognize certain nuclear fuel disposal costs as part of nuclear decommissioning costs. Third, the arbitrary "cut off" date for the incurrence of a "stranded cost" obligation should be eliminated or modified to recognize the fact that the Rules themselves impose continuing service obligations on "Affected Utilities" that may legitimately involve the incurrence of "stranded costs" on an ongoing basis during the aforementioned Transition Period.

III. STRANDED COST ISSUES

Q. WHAT ARE STRANDED COSTS?

A. The Rules define stranded costs as:

> ...the net verifiable difference between:
>
> a. The value of all the prudent jurisdictional assets and obligations necessary to furnish electricity (such as generating plants, purchased power contracts, fuel contracts, and regulatory assets), acquired or entered into prior to the adoption of this Article; and
>
> b. The market value of those assets and obligations directly attributable to the introduction of competition under this Article.

Assuming that the word "value" in A.A.C. R14-2-1601(8)(a) is synonymous with "cost" (as all parties to the Stranded Cost Working Group have apparently assumed), this definition is generally adequate with the following exceptions. First, it is not clear whether or not nuclear fuel disposal costs for fuel already consumed or to be consumed to serve standard offer customers would be included. As discussed later, these costs should be included in the system benefits charge. Second, costs necessarily incurred after 1996 to implement retail competition or to meet the continued service obligations under the Rules should be included as stranded costs. Finally, although the above definition would encompass "regulatory assets," APS has excluded them from its calculation of stranded costs.

Q. WHAT WOULD BE INCLUDED IN POWER SUPPLY COSTS?

A. The major elements of power supply costs would include purchase power contracts that have a minimum term of three years, fuel expense, operation and maintenance expense, taxes, depreciation, interest, administrative and general expense and equity return.

Q. WHY MUST THE COMMISSION RESOLVE THE STRANDED COST ISSUE NOW?

A. "Affected Utilities," including APS, must have a stranded cost recovery mechanism approved and in place prior to the beginning of retail access or it will be inevitable that some customers will be able to evade their responsibility for such costs. Moreover, customers themselves should know what the stranded cost recovery mechanism will be **before** they leave their incumbent supplier rather than sometime after. Ideally, the stranded cost recovery mechanism should also be in place before new market entrants are certificated for the APS service area. This will help them better identify those customers most likely to benefit from their services.

Q. WILL THIS REQUIRE THE COMMISSION TO CONDUCT A FULL-BLOWN GENERAL RATE CASE FOR EACH OF THE "AFFECTED UTILITIES"?

A. No. There would be no need for such extensive rate case proceedings unless an "Affected Utility" is actually seeking to increase its current rates and charges as part of the stranded cost recovery process. Indeed, the Commission's own rules on rate filings (A.A.C. R14-2-103) are limited by their own terms to rate increases. This is not to say that the Commission should not require the utility to justify its filing, but merely that such justification need not rise to the level of a general rate case proceeding.

Q. IN ADDITION TO ESTABLISHING A STRANDED COST MECHANISM, MUST THE COMMISSION DETERMINE A TOTAL STRANDED COST AMOUNT FOR EACH "AFFECTED UTILITY?"

A. Not necessarily. This will depend on how the particular utility proposes to quantify and recover its stranded costs. For example, under the APS proposal outlined later in my testimony, there would be no need to estimate in advance such a total amount of stranded costs and therefor no need for APS to make an omnibus stranded cost "filing" as contemplated under the Rules. Rather, the Company would submit a series of annual filings to reflect the level of stranded cost recovery sought for the succeeding year. APS would anticipate making the first of these filings (for 1999) no later than thirty (30) days of the entry of a final order in this proceeding.

Q. HOW WOULD APS PROPOSE TO MEASURE ITS STRANDED COSTS?

A. In general, the Company supports the lost revenues method (i.e., the difference between expected revenues under cost-of-service regulation and revenues under market-based pricing), but with several important limitations on the use of that method.

Q. WHAT ARE THE LIMITATIONS TO WHICH YOU JUST REFERRED?

A. First of all, utilities should only be compensated for stranded costs during a defined period during which they are transitioning to fully competitive and unregulated generation pricing. This so called "Transition Period" should equal that period of time in which the power supply market is out of equilibrium, i.e., when market price is depressed below long term marginal generation cost. Once that period is over, supply resources should be permitted to succeed or fail based on their own economics without receiving either customer support or providing customer subsidies.

Second, the APS method avoids the inevitable debate over long term projections of market prices, power supply costs, and sales (and then discounting them into current dollar amounts) that are often associated with the lost revenues method.

Q. WHEN WOULD THIS TRANSITION PERIOD END?

A. As is discussed later, the Company believes that the regional imbalance will be rectified by 2007, and thus the Transition Period would extend only through 2006.

Q. WHAT WOULD BE THE ACTUAL MECHANICS OF THE APS PROPOSAL?

A. Stranded costs would be measured annually during the Transition Period by comparing the Company's actual power supply costs and actual market prices for the preceding year. Because the first year (1999) would necessarily have to rely on estimates of market price, there could be a one-time true up after that first year. I have provided a chart explaining the four (4) steps to our proposal as Schedule JED-2.

Q. HOW WOULD ACTUAL MARKET PRICES BE DETERMINED FOR A PARTICULAR YEAR?

A. Arizona could take advantage of the California Power Exchange (PX), or a similar market price indicator, to determine actual market prices in Arizona. This may be accomplished by taking the hourly PX prices and adjusting them for the administrative charges to support the PX and the transmission charges and line losses to the Palo Verde substation. This will result in an actual market price for power delivered in Arizona. The hourly market price would then be matched to APS power supply to determine stranded investment. Again, a more detailed explanation is set forth in Schedule JED-2.

Q. IS THIS THE SAME METHOD OF MEASURING STRANDED COST AS PROPOSED IN THE COMMISSION'S STRANDED COST WORKING GROUP REPORT?

A. Absolutely not. The working group report would stretch the measurement period out some twenty (20) or thirty (30) years and the recovery period to at least ten (10). It would use long range estimates of both generation costs and market prices, which would then be reduced to a single present value amount, and which would thereafter require frequent true up proceedings.

Q. WHY IS LIMITING THE STRANDED COST MEASUREMENT PERIOD IMPORTANT?

A. In addition to those practical advantages discussed later in my testimony, our goal ought to be to transition generation prices to a fully competitive market as quickly as possible rather than essentially continue with traditional cost of service regulation of the present stock of generating assets for decades into the future.

Limiting stranded cost measurement and recovery to a relatively brief Transition Period also matches the solution with the problem. The largest cause of stranded cost is the current market imbalance caused by the relative oversupply in the Western Systems Coordinating Council ("WSCC") of both capacity and energy. It is ironic to note that the existence of these same low operating cost "excess" generating units also served as the economic justification for the very interconnected regional transmission system that allows for a competitive generation market. These factors will keep market price below the industry's long run marginal cost of generation for at least the next seven (7) years. Schedule JED-3, which is attached to my testimony, shows that regional reserve margins exceed 12% (the level needed for reliable system operations) until that time. This oversupply of generation and the concomitant existence of a regional transmission grid were the direct results of traditional regulation's focus on reducing long run revenue requirements and maintaining extraordinarily high levels of reliability. These impact the entire region irrespective of any single utility's resource decisions. For example, APS is itself already purchasing capacity from others to reach even this 12% reserve margin.

However, once the market imbalance has been rectified over time, and market prices approximate long run marginal cost, there is no need to continue stranded cost recovery.

Q. WHAT ARE THE OTHER ADVANTAGES OF THE COMPANY'S PROPOSAL?

A. Although widely used or being considered as a measure of stranded costs in other jurisdictions, the "lost revenues" approach to stranded cost measurement has been criticized for its reliance on long range market price estimates, present value discount rates, etc. By merely reducing the period being examined for stranded costs, these problems can be greatly lessened. Under APS' proposal, they are eliminated entirely. The use of actual costs and market prices obviates the need for long range estimates. The calculation of these on an annual basis means no need for repeated true up proceedings and no arguments over what discount rate is to be applied to future estimated revenue and cost figures. Additionally, the calculation of APS generating costs during the Transition Period will automatically reflect any new generating costs incurred post-1996 to meet the Company's "standard offer" obligations.

Q. FROM WHOM WOULD THE COMPANY'S STRANDED COSTS BE RECOVERED?

A. All APS customers (including partial requirements and standby or back up service customers) should bear a fair proportion of the Company's stranded costs during the designated Transition Period. For "Standard Offer" customers, the recovery would be implicit in the traditional rate setting process. For those customers taking advantage of direct access to acquire competitive generation services, there would have to be an explicit transition charge.

Q. WHAT ABOUT THOSE CUSTOMERS THAT LEAVE THE APS SERVICE AREA OR WHO COMPLETELY DISCONNECT THEMSELVES FROM THE APS SYSTEM?

A. Although an equitable argument can be made that these customers should also be assessed their share of stranded costs, as a practical matter, there is little way to collect such costs once the departing customer in question no longer receives any regulated services from the Company.

Q. HOW WOULD THE ANNUAL LEVEL OF STRANDED COSTS BE ALLOCATED TO SPECIFIC CUSTOMER CLASSES AND RATE SCHEDULES?

A. First of all, I make no claim of being a cost of service or rate design expert. However, it has long been APS' position that stranded costs should be allocated along traditional cost of service criteria and collected through a combination of kWh and kW distribution charges.

Q. WHY ARE REGULATORY ASSETS NOT INCLUDED IN THE COMPANY'S MEASUREMENT OF STRANDED COSTS?

A. In the Company's 1996 Rate Settlement (Decision No. 59601), the Commission ordered that all regulatory assets be amortized and collected in rates by 2004. Because these assets were both identified and their recovery assured in that proceeding, there is no need to separately address them now.

Q. DOES THE COMPANY'S PROPOSAL FOR THE MEASUREMENT AND RECOVERY OF STRANDED COSTS RAISE ANY UNIQUE ACCOUNTING ISSUES UNDER FASB NO. 71?

A. No. We have developed an approach that essentially eliminates the many complex accounting issues that could otherwise arise under other approaches to stranded cost recovery.

Q. HOW WOULD APS PROPOSE THAT MITIGATION BE HANDLED?

A. The Commission should first understand the proper scope of what can reasonably be characterized as "mitigation." This includes expanded sales of competitive generation both within and without the Company's traditional service area and cost reductions reasonably achievable during the Transition Period. "Mitigation" does not entail any responsibility to engage in new and unrelated enterprises. "Mitigation" does not mean taking profits earned by either the utility or its affiliates in unrelated enterprises and using them to subsidize stranded cost recovery.

With that understanding, I would initially point to past mitigation efforts. APS has been steadily reducing its costs since 1990, has reduced prices three (3) times, and will request an additional price reduction later this year. In determining the appropriateness of any future mitigation for 1999 and beyond, the Commission should not penalize the Company for its mitigation efforts prior to 1999.

IV. AMENDMENTS TO RULES

Q. IS APS PROPOSING ANY SPECIFIC CHANGES TO THE COMMISSION'S RETAIL ELECTRIC COMPETITION RULES?

A. There are many changes necessary in the Rules but not necessarily to the Commission's Rule on Stranded Cost, A.A.C. R14-2-1607 ("Electric Competition Rule 1607"). The number of changes found appropriate by the Commission will in part depend upon the degree of uniformity regarding stranded cost measurement and recovery imposed by the Commission in this proceeding.

Q. ARE SOME GENERIC CHANGES IN THE RULES APPROPRIATE?

A. Yes. These include: (1) changing the definition of "stranded costs" to actually use the word "cost" and to allow inclusion of post-1996 costs; (2) deleting the first sentence from Electric Competition Rule 1607(J); and (3) amending Electric Competition Rule 1607(A) by substituting the word "reasonable" for the term "every feasible", adding the words "directly related to regulated utility services" after the word "measure" and, lastly, by striking the words "or offering a wider scope of services for profit, among others" and substituting therefor the words "or reducing generation/purchased power costs."

The first sentence of subsection J is inconsistent with the definition of stranded costs used in the Electric Competition Rules. It is also inconsistent with subsection H of the very same Electric Competition Rule. Both the Legal Issues Working Group and the Stranded Costs Working Group have favored amending this provision. Finally, Electric Competition Rule 1608 should be amended to specifically include nuclear fuel disposal as part of the nuclear decommissioning costs already expressly covered by the proposed "System Benefits Charge" ("SBC").

The Company's third proposed amendment eliminates the impossible and never ending task of attempting to examine **every** conceivable business venture that might turn a profit and then determine whether or not the utility should have engaged in this or that venture. It avoids the troublesome cross-subsidy issue that has so vexed potential competitors of non-utility services. Lastly, it also eliminates the likelihood that the Commission will push "Affected Utilities" into foolish business ventures in an effort to meet an impossibly high standard of mitigation, thus creating the possibility of yet additional stranded costs.

In Electric Competition Rule 1608, the Commission has already recognized the need to recover nuclear decommissioning costs as part of the SBC. Nuclear fuel disposal is an inherent part of total nuclear plant decommissioning, and it is just as vital that there be an assured source of funds in the future to pay for that fuel disposal. Although at the present time, the amount assessed by the Department of Energy is only 1 mill per kWh, actual costs for this service in the future are necessarily uncertain. APS' proposal to limit the period for which stranded costs would be measured and recovered was premised on the belief that nuclear fuel disposal would be handled outside the stranded cost process.

Q. HAVE YOU PROVIDED A SPECIFIC MARK-UP OF THE RULES AS REQUESTED IN THE DECEMBER PROCEDURAL ORDERS?

A. Yes. It is attached as Schedule JED-4.

V. CONCLUSION

Q. IN CONCLUSION, WOULD YOU CARE TO AGAIN SUMMARIZE YOUR MAJOR POINTS?

A. Yes. The Commission must address the stranded cost "issue" prior to the advent of retail competition in 1999. This will necessitate a filing by each "Affected Utility" although such filing would, in the case of APS, not seek a specific "total" stranded cost amount. Moreover, the filing need not involve a full-blown general rate proceeding. For its part, the Company would propose to make its first annual filing within thirty (30) days of the final order in this proceeding.

The measurement and recovery of stranded costs (excluding regulatory assets) should be limited to the period of generation market imbalance or roughly the period through 2006. This not only avoids extended and speculative arguments over events far into the future and whose present value is even less significant, but provides for an orderly transition to fully market-based and deregulated competitive generation prices and provides some certainty to APS customers as to the duration of their stranded cost responsibility. The "lost revenues" method is a reasonable calculation of stranded costs during the aforementioned Transition Period.

APS already has regulatory approval for the amortization and collection of regulatory assets, and thus has excluded regulatory assets from its calculation and recovery of stranded costs. Similarly, the costs associated with disposal of nuclear fuel burned prior to 1997 or during the Transition Period to serve "Standard Offer" customers is best treated as a component of nuclear plant decommissioning under the SBC. Finally, stranded costs should include costs necessarily incurred after 1996 to meet the Company's continuing service obligations under the Rules.

All APS customers should pay their fair share of stranded costs. Such costs should be allocated to specific customer classes and rate elements using traditional cost of service and rate design criteria.

The Commission's rule on stranded cost should be amended consistent with my comments herein. A detailed legislative style mark up of the rules is attached to my testimony as Schedule JED-4.

Q. DOES THIS CONCLUDE YOUR DIRECT WRITTEN TESTIMONY?

A. Yes.

SCHEDULE JED-1

Jack E. Davis is Executive Vice President of Commercial Operations for Arizona Public Service Company. As Executive Vice President of Commercial Operation, Mr. Davis has responsibility for Bulk Power Trading, Transmission Planning and Operations, Customer Service, Marketing and Economic Development, and Pricing, Regulation and Planning.

Mr. Davis graduated from New Mexico State University in 1969 with a Bachelor of Science Degree in Medical Technology and in 1973 with a Bachelor of Science in Electrical Engineering. He joined Arizona Public Service Company that same year and has held various supervisory and managerial positions in both the System Planning and Power Contracts and Systems Operations Departments. In 1990, Mr. Davis was named Director of System Development and Power Operation and thereafter promoted to Vice-President of Generation and Transmission in 1993. In October 1996, he was named Executive Vice President of Commercial Operations.

Mr. Davis is the President of the Western Energy Supply and Transmission, Vice Chairman of the Western Systems Coordinating Council (WSCC), a member of the WSCC Board of Trustees, and (past chairman of the WSCC Regional Planning Policy Committee), a member of the National Electric Reliability Council Board of Trustees, President of the Western Systems Power Pool and a member of the Southwest Regional Transmission Association Board of Trustees. Additionally, he is a registered professional electrical engineer in the State of Arizona.

SCHEDULE JED-2

APS STRANDED COST METHODOLOGY

Four Step Approach to Calculate Stranded Cost Recovery Charge ("SCRC") for APS

- **STEP 1 <u>Determination of Hourly Market Prices</u>.**

Market prices will be determined by reference to the California PX market in dollars per MWH for the Southern California Hub as adjusted for:

1. Transmission wheeling (if any)
2. Administrative charges by the ISO/PX.
3. Transmission losses

This hourly price is the Market Price at Palo Verde.

- **STEP 2 <u>Determination of APS Retail Market Revenues</u>.**

Actual hourly loads are multiplied by hourly market price from Step 1 to determine hourly revenues which could have been produced if APS were to sell its power supply in the competitive market. Summation of this hourly dollar value across daily / monthly / annual hours produces annual revenues.

- **STEP 3 <u>Determination of the Actual Power Supply Costs</u>.**

The actual costs will be obtained from relevant financial and accounting data. Examples of the costs include:

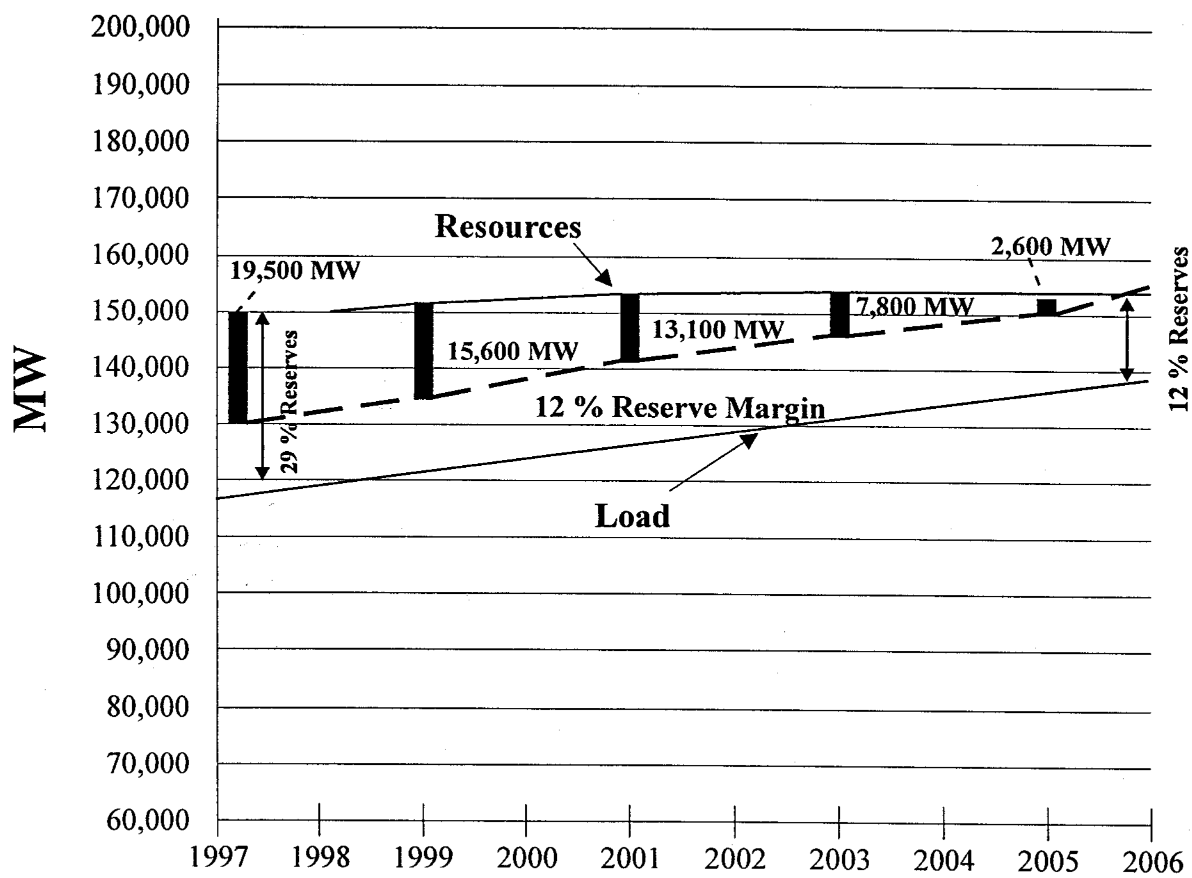
1. Fuel costs
2. Purchased power costs
3. O&M Costs including A&G allocation
4. Depreciation expenses
5. Interest expenses
6. Taxes (other than income)
7. Common and preferred shareholder equity expenses and
8. State and Federal Income taxes

- **STEP 4 <u>Calculation of the SCRC</u>.**

If the amount of APS costs (Step 3) is greater than APS Retail Market Revenues (Step 2), the difference will then be allocated among APS rate classes under traditional cost allocation and rate design principles and will be charged to customers taking competitive generation service on a demand and/or energy basis, depending on the customer's class.

SCHEDULE JED-3

WSCC Loads & Resources (Summer)



SCHEDULE JED-4
(Page 1 of 4)

R14-2-1601. Definitions

8. "Stranded Cost" means the verifiable net difference between:

   a. The ~~value~~ COST of all the prudent jurisdictional assets and obligations necessary to furnish electricity (such as generating plants, purchased power contracts, fuel contracts, and regulatory assets)~~ acquired or entered into prior to the adoption of this Article~~, under traditional regulation of Affected Utilities; and

   b. The market value of those assets and obligations directly attributable to the introduction of competition under this Article.

R14-2-1607. Recovery of Stranded Cost of Affected Utilities

A. The Affected Utilities shall take ~~every feasible~~ REASONABLE, cost-effective measureS DIRECTLY RELATED TO REGULATED UTILITY SERVICES to mitigate or offset Stranded Cost by means such as expanding wholesale or retail markets, ~~or offering a wider scope of services for profit, among others~~ OR REDUCING GENERATION/PURCHASED POWER COSTS.

B. The Commission shall allow recovery of unmitigated Stranded Cost by Affected Utilities.

C. A working group to develop recommendations for the analysis and recovery of Stranded cost shall be established.

   1. The working group shall commence activities within 15 days of the date of adoption of this Article.

   2. Members of the working group shall include representatives of staff, the Residential Utility Consumer Office, consumers, utilities, and other Electric Service Providers. In addition, the Executive and Legislative Branches shall be invited to send representatives to be members of the working group.

   3. The working group shall be coordinated by the Director of the Utilities Division of the Commission or by his or her designee.

D. In developing its recommendations, the working group shall consider at least the following factors:

   1. The impact of Stranded Cost recovery on the effectiveness of competition;

   2. The impact of Stranded Cost recovery on customers of the Affected Utility who do not participate in the competitive market;

   3. The impact, if any, on the Affected Utility's ability to meet debt obligations;

4. The impact of Stranded Cost recovery on prices paid by consumers who participate in the competitive market;

5. The degree to which the Affected Utility has mitigated or offset Stranded Cost;

6. The degree to which some assets have values in excess of their book values;

7. Appropriate treatment of negative Stranded Cost;

8. The time period over which such Stranded Cost charges may be recovered. The Commission shall limit the application of such charges to a specified time period;

9. The ease of determining the amount of Stranded Cost;

10. The applicability of Stranded Cost to interruptible customers;

11. The amount of electricity generated by renewable generating resources owned by the Affected Utility.

E. The working group shall submit to the Commission a report on the activities and recommendations of the working group no later than 90 days prior to the date indicated in R14-2-1602.

F. The Commission shall consider the recommendations and decide what actions, if any, to take based on the recommendations.

G. The Affected Utilities shall file estimates of unmitigated Stranded Cost. Such estimates shall be fully supported by analyses and by records of market transactions undertaken by willing buyers and willing sellers.

H. An Affected Utility shall request Commission approval of distribution charges or other means of recovering unmitigated Stranded Cost from customers who reduce or terminate service from the Affected Utility as a direct result of competition governed by this Article, or who obtain lower rates from the Affected Utility as a direct result of the competition governed by this Article.

I. The Commission shall, after hearing and consideration of analyses and recommendations presented by the Affected Utilities, staff, and intervenors, determine for each Affected Utility the magnitude of Stranded Cost, and appropriate Stranded Cost recovery mechanisms and charges. In making its determination of mechanisms and charges, the Commission shall consider at least the following factors:

1. The impact of Stranded Cost recovery on the effectiveness of competition;

2. The impact of Stranded Cost recovery on customers of the Affected Utility who do not participate in the competitive market;

3. The impact, if any, on the Affected Utility's ability to meet debt obligations;

4. The impact of Stranded Cost recovery on prices paid by consumers who participate in the competitive market;

5. The degree to which the Affected Utility has mitigated or offset Stranded Cost;

6. The degree to which some assets have values in excess of their book values;

7. Appropriate treatment of negative Stranded Cost;

8. The time period over which such Stranded Cost charges may be recovered. The Commission shall limit the application of such charges to a specified time period;

9. The ease of determining the amount of Stranded Cost;

10. The applicability of Stranded Cost to interruptible customers;

11. The amount of electricity generated by renewable generating resources owned by the Affected Utility.

J. ~~Stranded Cost may only be recovered from customer purchases made in the competitive market using the provisions of this Article.~~ Any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand reduction attributable to any cause other than the retail access provisions of this Article shall not be used to calculate or recover any Stranded Cost from a consumer.

K. The Commission may order an Affected Utility to file estimates of Stranded Cost and mechanisms to recover or, if negative, to refund Stranded Cost.

L. The commission may order regular revisions to estimates of the magnitude of Stranded Cost.

R14-2-1608. System Benefits Charges

A. By the date indicated in R14-2-1602, each Affected Utility shall file for Commission review non-bypassable rates or related mechanisms to recover the applicable pro-rata costs of System Benefits from all consumers located in the Affected Utility's service area who participate in the competitive market. In addition, the Affected Utility may file for a change in the System Benefits charge at any time. The amount collected annually through the System Benefits charge shall be sufficient to fund the Affected Utilities' present Commission-approved low income, demand side management, environmental, renewables, and nuclear power plant decommissioning AND NUCLEAR FUEL DISPOSAL programs.

B. Each Affected Utility shall provide adequate supporting documentation for its proposed rates for System Benefits.

SCHEDULE JED-4
(Page 4 of 4)

C. An Affected Utility shall recover the costs of System Benefits only upon hearing and approval by the Commission of the recovery charge and mechanism. The Commission may combine its review of System Benefits charges with its review of filings pursuant to R14-2-1606.

D. Methods of calculating System Benefits charges shall be included in the workshops described in R14-2-1606(I).